MARIGINAL COST BASED TARIFFS IN
INDIAN POWER SECTOR - A CRITICAL REVIEW

Dr. A. Bhattacharaya

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Tata Energy Research Institute,
7, Jor Bagh,
New Delhi.

CONTENTS

Page No.

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INTRODUCTION

An electric utility is aimed at constructing sufficient generating capacity to meet its demand over the planning horizon. This capacity will usually include a mix of baseload, intermediate and peaking plants. The generation mix and the resulting capital costs of a system constructed to serve only the peak would be quite different from a system constructed to serve load patterns that utilities commonly experience.

The objective of the present paper is to provide a framework which will aid the planner at utility level in the understanding of marginal methodology to conduct time-differentiated marginal cost based tariffs. In the following sections,a logical framework will be developed to analyse the three parameters of cost causation: capacity, energy and customers, in consonance with existing literature. Additionally, the paper will translate the principles of cost causation, to tariffs with the help of available data for nine SEBs[1].

CAPACITY COSTS

The determination of the marginal cost of generating capacity requires an understanding of the planning process. The utility planner attempts to meet the loads depicted by the load duration curve by choosing the least possible cost plan out of plans capable of supplying the anticipated loads. The planner chooses the best plan by means of a series of economic trade-offs between the operating and capital cost characteristics of the available kinds of capacity, and the requirements of the load duration curve.

For each possible plant, there is a series of total costs per kilowatt according to the number of hours the plant is used. As the number of hours of use increases, there comes a point at which additional operation of this unit will result in a higher total cost than if some other unit were to be used. There are three kinds of units available : (a) peaking units having low capital costs and high running costs, (b) cycling units having medium capital costs and medium running costs, and (c) base load units having high capital costs and low running costs.

The planner attempts to fill up the area under the load duration curve in order to minimize total costs by (i) selecting an amount of base load capacity such that the minimum number of hours any unit of base load capacity runs is the number of hours at which the total cost of a unit of baseload capacity is less than or equal to that of a cycling unit, (ii) using an amount of cycling capacity defined in a similar manner, and (iii) filling the remaining area with peaking units.

It is imperative to determine the time differentiated marginal costs that increments in demand actually impose upon the system. This can be done by measuring the increase in costs that would result from an increment in demand at any time corresponding to the load duration curve. In the short run, before capacity can be adjusted, the marginal cost is the cost of energy for the hours served plus the shortage cost for the hours not served. In the long run, after capacity has been adjusted, the marginal cost is the cost of energy plus the cost of capacity at peak. After a new plant addition, the short run capacity costs (probable shortage cost) will be lower than the long run capacity costs (cost of a peaker). As demand grows, the probable shortage costs approach and exceed the costs of peaking plant, triggering more capacity additions. For tariff fixing we can think of a plant continuously adapted to demand in which the long run marginal cost of capacity is also the appropriate short run cost of curtailment.

1. State Electricity Boards (Bihar, Delhi, Gujarat, Haryana, Maharashtra, Punjab, Rajasthan, Uttar Pradesh and West Bengal).

2. It is the plant that yields the lowest present worth of all costs to be incurred over the life of the equipment to be used in carrying out the plan.

The marginal cost of capacity will be the cost of that plant used to meet the load (at peak) having the shortest duration. In the case of utilities having a highly peaked daily load curve, the marginal cost of capacity will generally be the cost of a peaking plant. However, utilities having the long term capability of utilizing stored hydro energy (either impounded or pumped) may never use a peaking plant even in long run equilibrium. Here, the capital costs would be higher than the cost of a peaker and running costs at the peak would be commensurately lower.

Utilities having less peaked daily load characteristics may find no portion of the load duration curve of short enough duration so that the least total cost method of serving the load would be to build and run peaking plants. In this case, the cost of the plant used to meet the peak of relatively long duration should be used as the marginal cost of capacity. Running costs at the peak will be lower than if a peaking unit were used. A utility with a very high load factor may therefore, show little variation in hourly responsibility for capacity related costs[3].

The marginal cost of generating capacity must be adjusted upwards to account for the reserve margin required to meet the planning criterion. The pertinent reserve margin would be required so that load and capacity do match perfectly. Thus the planner can relate the cost of a kilowatt taken at the point of consumption to the installed cost of capacity required to serve the load at an appropriate risk of shortage.

In cases of persistent over (under) capacity, the marginal shortage costs associated with prices based on long run marginal costs and the consumption levels resulting from such prices might be very small (large). In these circumstances, we might want to depart from long run marginal cost pricing in favour of short run marginal cost pricing so that the installed capacity can be utilized efficiently. Since we expect that, over time, excess (shortage) capacity will be eliminated, short run marginal costs will necessarily rise (fall) towards long run marginal cost. Except under extreme conditions of excess capacity or shortages of capacity, we may, therefore, recommend that prices be geared to the long run marginal cost of capacity.

3. The capacity costs will be charged over a larger number of hours since the relatively leveled load curve will probably cause many more hours to have a significant LOLP.

There may be other kinds of imbalance that will affect the marginal generating capacity cost. Some exogenous factor e.g., oil embargo of 1973 may distort the generation plant mix for the utility concerned. As nuclear base load plants come on line, relatively new and high efficient oil plants will be pushed up in the load duration curve. In systems having relatively high load factors, such plants might be used in cyclic fashion (i.e., for a week or for a month at a time) to meet peaks. In this particular case, the marginal cost of capacity could be the cost of not pertaining such units in the system.

One can also have system imbalance where the amount of water to meet total annual energy requirements is insufficient in the presence of sufficient hydraulic peaking capacity. Here, the marginal cost of capacity (i.e., the addition of a waterwheel generator at an existing dam site) will be less than that of a combustion turbine.

Capacity cost in Indian Sebs

This review evaluates the methods and assumptions used by nine Indian SEBs (e.g., Bihar, Delhi, Gujarat, Haryana, Maharashtra, Punjab, Rajasthan, Uttar Pradesh and West Bengal). Two different methods are used to estimate capacity costs. First, a number of studies (Delhi, Haryana, Punjab and Rajasthan) estimate these costs by calculating the average cost per unit of additional capacity (KW or MW) for the next (or most important) plant that will be brought on line and then correcting for O & M costs, capacity margins/utilisation factors, and peak period loss factors so as to determine generation capacity costs at various voltages. The summary of assumed system parameters are given in Table 1, whereas transmission, distribution and simultaneity factor (inverse of diversity factor) will be taken up in subsequent sections.

The estimates of O & M costs are relatively high in a number of studies (Bihar, Delhi, Haryana and Punjab). Such estimates may overstate the O & M costs associated with new capacity. They may, however, differ significantly from the average (historical) values for existing capacity. Also, historical values may reflect inefficiencies and non optimal system design which will gradually be reduced in the future. One should not be overly optimistic and thus unnecessarily adopt accepted international standards. By the same token, one need not assume that no improvements in system design and operation will be achieved in near future.

Table 1 : Assumed System Parameters

SEB	O&M COSTS (as % of capital costs)	Peak Period Energy Losses (%)	Simultaneity Factors (Inverse of Diversity Factor)	Plant Life (year)	Capacity Margin (%)	Discount Rate	Time period
1	2	3	4	5	6	7	8
Bihar	G:5.3; T:4; D:3-6	EHV: 4 D: 8-13		30 (Th)	H: 12.5 Th:39	10	1976-81
Delhi	G:3; T:2; D:8	G:8; T:13; D:5-10	220 KV/ 32 KV :.96 33 KV :.90 11 KV/ 4 KV :.90	25 (Th)	30	10	1977-82
Gujarat	G, T, D: 3	EHV: 10 D: 7-11	EHV :.85 HT :.65 LT :.65	30 (Th)	30 (Th)	10	1977-81
Haryana	G:3; T: 8-10	G:13; T:2.6; D:2.6	220 KV/ 132 KV :.80 132 KV/ 66 KV :.70 66 KV/33 KV :.65 33 KV/11 KV :.60	30	30	10	1977-80

1	2	3	4	5	6	7	8
Maharashtra	G,T,D : 2.5	EHV: 7 D : 8-24		30 (Th)	35 (Th)	10	1977-84
Punjab	G:3; T:2; D:8,	G:11; T:6.6; D:6.1-6.6	33 KV :.96 11 KV :.90	25 (Th)	30	10	1977-79
Rajasthan	G:1;T:1-1.5; D:3	G:13; T:2.6 D:7.8	220 KV/132KV :.91 132 KV/33 KV :.77 33 KV/11 KV :.62	30	40	10	1977-84
Uttar Pradesh	G:3; T:1-3; D:3	EHV : 4.9 D : 5.6-9.9	EHV :.71; 33KV:.71 11KV:.71-.83 LT : .71-.83			10	1976-81
West Bengal	G,T,D: 2	EHV : 5 D : 5-25	EHV :.91 33KV:.83 11KV/6.6KV:.71 LT:.67	25(Th) 45(H)	39 (Th)	7	1977-84

NB: Read G for Generation, T for Transmission, D for Distribution, H for Hydro, Th for Thermal.
Source:Central Electricity Authority, New Delhi.

Assumptions concerning plant life seem to be conservative, especially in those states (Delhi, Punjab and West Bengal) that assume a 25 year lifetime for thermal plants. Technological progress can yield better lifetime in the planning horizon considered. Moreover, capacity margins may be too high (Bihar, Maharashtra, Rajasthan, and West Bengal) especially since capacity shortages exist in these states. The loss factors, which are discussed at a later stage in this paper, vary widely between states and appear high for new capacity (Delhi, Gujarat and Maharashtra). The Haryana and Rajasthan studies apparently take the loss factors without reference to their systems. Surprisingly, one study (West Bengal) uses a discount rate that is likely to be below the marginal return to public sector capital. Some studies (e.g. Gujarat, Rajasthan and West Bengal) have built the projected inflation into the cost estimates. Finally, none of the studies have considered the use of shadow prices as a way of more accurately measuring resource costs to the economy.

There are number of problems in capacity cost estimation as performed by SEB's. It can lead to considerable tariff fluctuations as each new plant is brought on line. It can also result in an underestimation of capacity costs (as defined) if additional demand is less than additional capacity. However, this is unlikely to be the case in SEB's since most of them have capacity shortages. In addition, little consideration is given to whether this plant will supply marginal amounts of electricity or to whether any fuel savings will be realised as a result of the addition of this plant. Finally, this approach results in a too narrowly defined estimate of generation capacity cost since it ignores the fact that a current increment in demand can affect capacity investments subsequent to the one considered.

The remaining studies measure average capacity cost over a short run period, by dividing generation capacity investment over a (five to seven) year period by resulting additional capacity and correct for loss factors and capacity margin to arrive at an average cost estimate. This approach derives estimates based on too short a time horizon and ignores the fact that future expenditures must be discounted to measure their present worth. The potential fuel savings resulting from the addition of more efficient plants have not been taken into account. The West Bengal study determines a separate average capacity cost for each year between 1977-84. It is clear that such a measure of capacity costs would clearly result in frequent fluctuations in tariff.

In average capacity cost approach, cost estimates are adjusted to allow for the fact that not all additional capacity is used at all times to supply electricity. Particularly, in the Bihar, Uttar Pradesh and Maharashtra studies, cost per KW of installed capacity are divided by utilisation factor. Since the utilisation factor is an energy related measure i.e., it measures energy supplied as a fraction of maximum potential energy supplied, this is not an appropriate method of adjusting capacity costs. The method used in the Delhi, Haryana, Punjab and Rajasthan studies, where generation capacity costs are multiplied by 1+capacity margin, is more satisfactory.

Energy Costs

The planner tried to meet forecasted peak and energy requirements by means of the least cost combination of existing equipment plus future additions of equipment representing current best technology at currently known costs. Thus marginal energy costs must be viewed over a period of time rather than at a particular point in time.

For a typical thermal system, in equilibrium, the marginal generating cost at any hour is given by the energy cost of the last unit on line at that hour, plus the share of the marginal capacity cost implied by the relative probability that load will exceed capacity during that hour. To determine the marginal energy cost at any hour, we have to determine the fuel and variable operating costs of the last unit on line. This concept is also familiar to utility despatchers and is often referred to as the system "Lambda". It is calculated as the cost of the next increment in load and is often the basis for economy interchange transactions.

The determination of the marginal energy (running) cost for a prospective period is based upon utility's production cost data. One may design a production cost model, for each hour of the year, which will consider the expected load, available capacity (given planned maintenance and forced outages) and the uncertainties of the forecasts, and will compute the most likely cost of an additional increment in load for the hour. Once the marginal unit has been determined over the range of the load duration curve, a running cost is assigned to each unit. In fact, this will be the fuel cost per kilowatt hour based upon the incremental heat rate (may be average heat rate in practice) at that stage of the unit's loading. The energy related portion of operation

and maintenance expenses per kilowatt hour should also be included in the running cost. The power production and maintenance expenses will be related to the existence of the plant and remain fixed, vary with the rate at which the plant is used in relation to designed maximum capability or vary with the total energy output of the plant. For example, the maintenance expenses of boiler plant, in part, may arise from demand and in part by continued usage.

The data at this point may be actually or potentially hour-by-hour marginal cost data over a period of time. Since the eventual rates will not vary hour by hour, the costs are to be immediately grouped into those periods which have been tentatively selected as pricing periods. This is done by weighting the marginal cost for each hour by the total hourly load and deriving a weighted average marginal energy cost for each pricing period.

A review of these data over several years usually reveals two features (i) expected rise in general price level (ii) expected changes in relative price level between various fuels.

We first correct the data, using the general price level deflator used by the planners, to obtain a series of constant prices. In a well adjusted system, the costing period marginal running costs (in constant prices) tend to rise and fall throughout the planning period because capacity additions are made in discrete units, while growth in load is roughly linear. We can smooth these cost variations around the equilibrium level in order to make a tariff which reflects, for each daily or seasonal costing period, the central tendency of the marginal energy costs for those hours (in constant prices).

For systems with both hydro and thermal plants, the marginal energy cost can be imputed by examining the planning and operation of the system. If hydro is being despatched above a two mill machine and below a three mill machine, we essentially evaluate the hydro at between two and three mills. The precise value imputed depends on the number of hours the hydro is marginal. Since despatch plans usually treat hydraulic energy in an aggregate fashion, it is necessary to impute an energy cost to hydraulic energy for each of the costing/pricing periods (previously selected) during which this energy is marginal. For costing, hydro can be divided into three basic types : run-of river, pondage and pumped storage. The run-of-river hydro should be costed at the variable operation and maintenance

expenses of additional production. This energy becomes marginal very rarely. The second type of hydro, pondage, is much more likely to be marginal. The basis for costing pondage and pumped storage is the cost of the displaced energy. We can analyse points along the load curve and determine what energy is being displaced subject to the system's hydro operation. For example, if it is clear that hydro is used only to meet a portion of the load curve for which combustion turbines would otherwise be used, the marginal cost of that portion of the load curve for which hydro is marginal should be the cost of a combustion turbine.

However, for a utility which has a relatively large amount of hydro capacity, we can treat the hydro as a plant with its own characteristics, lying somewhere below the running cost of a peaker and above the cost of an intermediate. Here, one has to impute a cost to the hydraulic energy. In principle, the aim is to schedule the water to displace as much high-priced fuel as possible, within the limits of the plant's own capacity and water supply.

Pumped storage hydro is similar to pondage except that the actual cost of pumped storage is higher. The fuel cost of a pumped storage kilowatt-hour is the fuel cost of the thermal machine used for pumping, adjusted for efficiency. Hence, pumped storage energy must displace a machine with a higher cost than its own efficiency adjusted cost. The decision to pump and release is based upon this trade-off. Once the pumping is done, the objective of the planner is to utilize the potential energy in a way that displaces the highest priced fuel. The pumped storage resources, however, can be replenished regularly, whereas pondage will be subject to seasonal variation. Thus, pumped storage can displace lower cost energy than conventional pondage and results in a lower imputed energy cost.

The assessment of marginal energy cost is also subject to operating constraints peculiar to the system at hand. The marginal energy cost, in general, at any hour is the cost that will be incurred by an increase in consumption, or saved by a decrease in consumption, at that hour. In practice, it refers to the cost of the most expensive unit on line. But this may not be valid in certain circumstances e.g.:

(i) Many units cannot be cycled over the course of a day. A unit which is needed to provide capacity during the peak hours may not be taken off line at night but is

kept operating at a minimum loading. The loading on this unit will be neither decreased nor increased in response to demand at other than peak times. Thus, it may be the most expensive unit on line but, it is not the marginal one.

(ii) In order to maintain area protection and stable voltage throughout the system, utilities may run plants at key locations even though they are not the lowest cost source of energy.

(iii) The steam electric utilities may often run older plants to provide steam. These old units/plants may not respond to changes in demand for electricity. Hence they are not marginal units.

When systems concerned are far from optimality due to non-optimal plant mix, one may consider the use of short run marginal energy costs. For example, an oil fired system may add a nuclear plant in order to displace oil. The addition may be solely justified by the economics of the system i.e., as when the total capital and operating expenses of the nuclear plant are lower than the fuel cost of the oil plant. In this case, marginal energy cost over the planning horizon should be falling towards its long run level, while the short run capacity cost may be very low because of the excess capacity at the beginning of the period and rise towards its long run level. Here, it may be warranted to have the tariff reflecting the high cost oil which is being consumed to produce energy rather than the long run cost which signals the arrival of cheap energy[4].

Thus, it may be recommended in general, to compute the average of the marginal energy costs over the planning horizon.

Energy Costs in India Seb's

The Indian tariff studies estimate energy costs at various voltage levels by determining fuel costs per KWH and then correcting for appropriate average loss factors. These estimates for the various SEB's are summarised in Table 2. Energy costs are calculated for

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4. This is because to signal that nuclear energy is marginal (when this will not be true in some cases for possibly as long as 20 years) would be to invite the consumption of an expensive and scarce resource at a reduced price.

(i) a plant (typically the largest) that will be brought on line during the next five to seven years (Delhi, Gujarat, Haryana, Punjab and Rajasthan), (ii) the plants that will be added during this period (Uttar Pradesh and West Bengal) and (iii) the plants that will be running in a given future year (Bihar and Maharashtra).

Table 2 : Estimated Energy Costs

SEB	Energy Costs at the Plant (paise/KWH)
Bihar	9.01
Delhi	10.78
Gujarat	10.96
Haryana	10.84
Maharashtra	8.36
Punjab	11.27
Rajasthan	5.67 (Peak), 4.40 (Off-Peak)
Uttar Pradesh	13.40
West Bengal	6.13 (1978-79) 6.36 (1983-84)

Source: Central Electricity Authority, New Delhi.

The first approach comes closest to providing an appropriate estimate of energy costs. Its usefulness, however, depends on both the chosen plant being brought on line in the near future to meet the incremental demand, and on its being used to supply marginal amounts of electricity. Since new plants are typically more efficient than older ones, it is likely that new plants often do not operate at the margin. Hence, energy costs estimated on the basis of such new plants may under-estimate actual marginal energy costs.

The second approach yields an estimate based on future costs, but it results in an average, rather than marginal cost estimate. The third one results in an energy cost estimate that is based on both future and historical costs.

The Rajasthan study estimates both peak and off peak energy cost. Other studies (SEB's) have omitted this distinction by citing existing capacity shortages and extended periods of peak demand. The existence of

capacity shortages does not imply that periods of off-peak demand do not exist. This is because as long as there is more than one thermal plant providing base load, energy costs can vary with the level of demand.

Some SEB's (Bihar, Gujarat, Maharashtra, Uttar Pradesh and West Bengal) purchase significant amounts of electricity from neighbouring power grids. The costs of such purchases, which may in several cases provide reasonable estimates of energy costs during peak periods, are ignored. It is obvious that we could not use the price paid for such electricity (a financial measure) as an indicator of the cost. But we can determine the energy cost of the exporting power system. Perhaps, we might ignore this complexity in measuring marginal costs when power imports are expected to be eliminated in the near future.

Transmission Costs

There are two types of transmission investment (and associated O & M) that are more properly attributable to the generation function than to the transmission one.

(i) The costs that are incurred to utilize sources of cheap energy available only at locations remote from load centers, and

(ii) Costs associated with the establishment of power pool related EHV grids which reduce individual utility generation reserve requirements.

The decision in the first case to build these facilities is based on a trade-off between building a plant close to a load center (with no transmission) utilizing an expensive energy source and building a remote plant utilizing an inexpensive energy source plus the cost of transmission.

In the second case, the individual members of the pool may find that, by investing in an EHV grid, they could provide the desired level of reliability at a lower cost (through diversity) than would have been the case had each utility carried additional generating reserves. In both cases, these costs should be excluded from the

analysis of transmission investment[5].

The analysis of marginal transmission investment seeks to express the unit marginal cost in transmission facilities resulting from an increment or decrement in load. The transmission planner has to ensure that an adequate amount of power can be delivered to all points on the system at all times.

Thus, the capacity of the transmission network is determined by the peak load on the system and the outage contingency employed in evaluating transmission system reliability. Assuming that the cost of reliability properly reflects a trade-off with the cost of outage and will remain constant, relative to total transmission investment, the capacity of the transmission network will vary with the expected size of the peak demand. The marginal cost for transmission investment is, therefore, a cost per kilowatt of system peak demand.

High voltage transmission facilities consist of large costly components. The utility planner designs the system that will, over time, yield the least total cost subject to a set of forecast peak loads. This is done by choosing the number of corridors, the size of corridors and the transmission voltage level that most economically transport the expected loads. As voltage levels increase, the cost of corridors, towers and conductors all rise. With certain load densities, economies of scale may result from higher voltage transmission. The per kilowatt marginal cost of transmission investment is, therefore, not necessarily a linear function whereas the transmission investments tend to be lumpy.

The first step towards compute marginal cost of transmission investment is to investigate a time period of sufficient length such that lumpiness of investments or temporary fluctuations in peak load growth will not distort the result. In the next step, we unitize additional investment on the basis of which that investment was planned. Finally, transmission planning is done on the basis of peak demand.

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5. This is because these costs are already reflected in the cost of energy and the cost of reserves. For example, the fuel savings resulting from a remote generation site utilizing an inexpensive fuel is an offset to the capital cost of the plant and its associated transmission facilities.

In a system that is building up or running down the reserve margin, the capacity added to the transmission network at any specific time may not be related to peak additions. In this case, the additions to transmission capacity may more properly be related to additions to generation capacity. Only in the long run, when the incremental reserve margin approaches the desired system reserve margin, do the additions to peak load properly reflect the planned increase in the capacity of the transmission network.

Transmission O & M expenses are related to the amount of plant in existence. Thus, the addition of plant to meet additional peak demands will give rise to additional operation and maintenance expenses in proportion to the amount of plant added. In this sense, transmission O & M expenses are truly marginal costs.

The first step in the analysis of transmission O & M expenses is to analyze, on an account-by-account basis, actual transmission expenses for past few years and budgeted expenses for the planning period. Any extraordinary or expected non-recurring expenses should be adjusted to typical levels. Any despatch expenses relating to pool or interchange operations are energy related expenses and should be removed from the analysis of capacity related transmission O & M expenses. Such expenses should be analyzed to determine whether or not they are marginal costs. If they are, they must be included in marginal energy costs. Any expenses related to the maintenance of transmission lines built specifically to serve remote base load generation are part of the trade-off of the generation planning process and should be excluded from the analysis. Any fixed costs e.g., leased rentals or fixed payments to another utility for use of transmission facilities, are payments in lieu of capital and deserve to be omitted and treated as investment.

Distribution Costs

In distribution, unlike generation, marginal costs may vary between consumers, depending on location density, terrain and local codes. The system is planned to provide access to electric utility service for each potential consumer irrespective of the load, and it also has to carry the load. Investment in an electric distribution system is causally related to three factors: customers, demand and energy. The first factor should be viewed as a system capable of connecting all consumers but providing voltage only and no power. The

second one consists of the components necessary to accomodate the demands that consumers actually place upon the system. The last component refers to the least total costs that are achieved by placing in service distribution capacity greater than demand and thereby reducing energy losses.

The customer related marginal distribution costs are those directly attributable to the addition of a customer, as well as those varying in proportion to the number of customers, but not the level of demand. The number of meters and services will (with some exceptions) be equal to the number of premises served and might be thought of as hook-up costs. The number and cost of distribution line poles (for example) are also customer costs. In order to compute these costs, we seek the per customer cost of covering an electric utility's entire service territory with a distribution system capable of serving a population of minimum demand customers.

The minimum demand customer would have a maximum load of one-half kilowatt representing items as lights, auxiliary electrical equipments etc. The design of the minimum demand system would account for certain standards that must be met irrespective of demand (e.g., standards may be minimum pole heights to meet highway clearance, minimum conductor size to avoid sagging and a minimum transformer size to meet the economic considerations of ordering and maintaining inventories). The minimum system would not only reflect replacing all components currently installed with the minimum size component currently in use, but also a system that could serve all the utility's customers at the minimum demand level.

Since the ideal view of the customer related costs calls for providing voltage but no power, we would subtract from the costs computed, as above, the material costs associated with conductors and transfor- mers. The costs would then refer to all the labour costs, necessary to put together today's minimum system and all material costs except those of conductors and transformers.

Once these computations are made, we divide the total cost of the customer related system (in present price) by the total number of customers in order to obtain the marginal customer related distribution investment per customer. This cost may vary within a single service territory due to undergrounding and population density. In such cases, more than one marginal customer related

cost must be computed.

Demand related distribution costs would include the cost of conductors, transformers, and even such expenditures as the buying of distribution poles which will vary with demand.

At the level of the link to a customer which serves him alone, the maximum kilowatt demand, whenever it occurs, theoretically determines the size[6] of the facilities required. At the generator bus, however, it is customers' demand at the time of the system maximum load, that is pertinent. Between these extremes, the common distribution system is designed to serve the customer on the basis of the degree of coincidence between his maximum demand and the maximum demand of others.

Thus, we have to measure the additional cost of distribution facilities required when a kilowatt of load is added by a customer, taking into account the diversity of all customers' demands. Diversity consists not only of a time variance but also of a geographic variance[7]. So, in principle, one would want to consider each area separately to determine if the costs of service are different.

It thus follows that distribution cost will vary not only with a customer's maximum demand or contribution to peak demand, but also with his load characteristics. Ideally, we can analyze separately each level of the distribution system for which a different demand is considered to be the cost causative factor. We can meter each customer's probable contribution to demand at each time and assess cost in the most equitable way.

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6. This is because, in practice, the size of a facility may be invariant over a large range of kilowatt demands. The economics of purchasing and storing materials may dictate a standardization of sizes.

7. Given two separate geographic areas, one peaking at 8 a.m. the other peaking at 8 p.m., the same generating equipment can serve each peak, but the same distribution equipment cannot.

In practice, we seek to measure a distribution cost per kilowatt for a single measurable demand. Customers are grouped into classes having homogeneous load characteristics. Since tariffs are made on a class basis, cost computations should reflect class load characteristics.

There are three approaches to derive demand related distribution costs : (i) we may predict the kinds of equipment to be added to meet a load increment and compute the cost, (ii) we may use a statistical approach, and (iii) we can take the first difference in capacity related investments and in peak demand, over a period of time, and divide the former by the latter to obtain our estimate of the marginal unit cost.

The first approach suffers from infirmity i.e., internal growth of the system (which requires reinforce- ment of existing circuits, stations) is extremely difficult to measure in physical units. The second approach is preferred in most cases. Least squares regression technique is generally used. In third method, gross additions to distribution plant at constant prices are analyzed for a past period and a prospective period. It permits the recognition of extraordinary investment items, changing optimality criteria or improved technologies. A period of gross additions to distribution plant that will best represent the future level of marginal demand related distribution costs can be selected, and chosen as basis for marginal cost calculation. The expenditures for replacements of existing plant which are not related to additions[8] to load and customer related distribution plant are deducted from gross additions to distribution plant. The resulting figure, demand related additions to plant, is then divided by the additional coincident peak load added to the distribution system during the analysis period to obtain the marginal demand related investment cost in distribution facilities.

We have discussed the analysis only for the future period. Since optimality criteria upon which distribution is planned, may usually be changed and we are concerned with future marginal costs, we can ignore the historical analysis.

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8. Customer related distribution plant additions are defined as the product of the marginal per customer cost and the number of customers added during the chosen period of analysis.

In planning for a distribution system, it makes economic sense to plan well ahead. The labour involved in replacing wires as demand grows is too expensive to warrant sizing wires to current demand. A trade-off is made between the extra cost of installing more wire capacity than is needed at present and the cost of continually replacing it. Moreover, while a wire which is sized exactly to maximum demand will carry the load, the losses are reduced if the wire is sized larger, and a similar trade-off can be made on the optimum size of wire to carry a given expected load at minimum cost of wire and losses. These two trade-offs lead to most distribution systems being sized somewhat larger than the maximum load at any point in time, not simply to provide a reserve margin but because of the economics of the distribution system itself. As with the costs of generating capacity, distribution capacity related costs are common over time i.e., the capacity available today is there because of an anticipated aggregate load. The cost we seek is the per unit cost of capacity when the optimum loading for which we planned has been achieved. Hence, determination of the load by which we unitize gross investment requires understanding of the planner's optimality criteria.

Distribution O & M costs are occasional primarily by exposure of the system to the natural hazards of weather and time. To an extent, these expenses will vary with demand. Distribution substation expenses should be considered almost 100 % demand related. In the case of a line that was felled in a storm, the incident occured without regard to the size of the line and hence the maintenance cost of restoring the line (e.g., labour costs, conductor and equipment costs) will not vary with size of the line. These expenses are not demand related. The cost of returning the pole, dislocated by a car, to its original condition will not vary with the guy wire; but it may be related to the presence of the conductor, which, in turn, is related to demand . The cost of reguying the pole may then be demand related. Thus, distribution O & M expenses, excluding street lighting expenses and associated overheads, are generally split about 60% customer related and the 40 percent demand related components.

In analyzing distribution O & M expenses we prefer to look forward and backward for a couple of years. The first step is to segregate street lighting expenses and associated overheads from other expenses. These expenses are directly attributable to a small group of customers and should not be spread across all customers. Next, extraordinary and non-recurring expenses may be separated. This would include expenses due to sudden

damage and credits from insurance received due to such occurrences. Any divergence from the historical pattern should be examined by operating personnel. Total demand related expenses are divided by distribution system demand at time of system peak to arrive at a per kilowatt cost. Customer related expenses are divided by total customer served from the distribution system to arrive at per customer cost. These unit costs are then converted to constant prices using an appropriate index. Once in constant prices, the trend in these costs is examined and a level of costs is extrapolated to several years into the future. For purposes of stability in tariff, a single cost level, representing the mid point of a longer period within which technology is relatively constant, is preferable to annual changes in rates to reflect the trend of expenses.

Transmission and Distribution Capacity Costs in Indian Seb's

Most of the Indian tariff studies use a three step procedure to estimate transmission and distribution capacity:

(i) Estimate, on the basis of expansion plans, how much electricity will be transmitted and distributed at various voltage levels;

(ii) Determine per unit costs (either KM or KW) for transmission and distribution capacity, and

(iii) Multiply (i) and (ii).

The problem arises in many studies (Delhi, Maharashtra, Haryana, Punjab and Uttar Pradesh) in the resulting cost estimates which are not completely forward looking since historical data are used to derive estimates of unit costs. The outcome is the cost estimates which reflect a mixture of historical and future costs. Moreover, future costs are not appropriately discounted.

Marginal Cost Based Tariffs

After developing the long run marginal unit investments, it is necessary to determine how these investments should be converted into marginal carrying charge for

use in tariff structure.

It is recognised that a capital investment gives rise to three basic types of charges: taxes, return of capital (depreciation) and return on capital (earnings and interest). It is further assumed that investments are financed at the incremental cost of capital (based on the forecast costs of long term debt, preferred stock financing and common equity financing). We next seek to simulate the accounting charges that will arise from a particular investment. We accept as given the criterion of the revenue requirement being equal to the sum of taxes on earnings and property, depreciation of plant that is used and useful and earnings on net plant that is used and useful. Therefore, to compute the charges we must predict the service life and probable dispersion pattern of retirements for the investment. After doing this, we have a stream of mean annual surviving investments to which we can apply the straight line rate of depreciation and compute all the calculations pertaining to revenue requirements. After calculating the charges that will arise in each year over the life of the plant, we can calculate the sum of the present worth of the revenue requirements for various investments to determine which investment is least expensive.

In the next step, the levelized annual carrying charge is determined by dividing the present value of the revenue requirements by the present value of the mean annual surviving investment. It has the benefit of overtime, charging equal real costs for the same service in times of no inflation or technical progress simulating the price set by sellers in a competitive market place. If marginal cost based tariffs were to be put into effect, consideration would have to be given to the way goods are priced in the competitive market[9]. The bases for calculating electricity marginal costs would have to be comparable to the bases upon which all those competing for the electric utility capital are setting their prices.

The marginal cost of having a facility for a year, if computed for utilities in the same manner as for

9. The framework behind the use of marginal cost pricing for electricity services is the efficient allocation of resources.

competing goods and services, must recognise the rate of inflation or technical progress in electric utility facilities. While it is never easy or even possible to peg an exact rate of inflation or technical progress, it must be recognised that those compete for the utility capital are constantly forecasting these effects on prices. Hence, finally we have to spread the discounted present value of the revenue requirements in a series that rises annually at the expected rate of inflation net of technical progress. The basic inputs to the computation are the present value of all revenue requirements, life of the investment (time over which the total present value of revenue requirements will be payed back), net long term inflation rate of technical progress annually (annualization factor so arrived at is likely to be somewhat lower than the annualization factor levelized earlier), and annual carrying charge which rises at the rate of inflation.

It may be emphasised that this rate of inflation should be specific to the type of investment so as to capture the effect of relative price changes. The rate must also be the long term rate expected over the life of the investment. Using the rate of inflation net of technical progress, which may be developed by a given utility, would have the virtue of being consistent with the utility's planning decisions.

Our final computation of marginal cost (e.g. capacity, energy, transmission, distribution) needs to be refined because electricity utility systems are not 100 percent efficient . Each increment of load on the system gives rise to an incremental energy loss[10]. The further downstream from the generator that load is taken, the greater the loss. This means that the total input to the system must be greater than the sum of all loads measured at the point of consumption. It also means that each component of the system must be sized to accommodate the loads and losses of downstream system elements, as well as its own loads and losses.

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10. Losses can be broadly classified as copper losses, core losses and dielectric losses. They are caused, respectively, by the production of heat, the establishment of magnetic fields and the leakage of current. The first of these varies in proportion to the square of the load, while the latter two are fixed losses associated with specific equipment.

The expansion of the capacity of both the transmission and distribution system is proportional to the diversified maximum demands of the consumers served from the various elements of the system. These capacity related losses will occur after adjusting the system to meet a new load level. They are average losses at the time of system peak demand. The marginal losses (energy related losses) are based on the concept of additional energy supplied from a fixed system. They depend on the level of demand. Thus, in addition to deriving energy adjustment factors for each element of the system from which service is taken, we must also derive energy adjustment factors for each separate pricing period during which a different load level is expected to pertain. The appropriate load level is the average load prevailing during the period.

In Indian tariff studies no distinction is made between peak and average loss factors (Bihar, Gujarat, Uttar Pradesh, West Bengal). Most studies assume peak loss factors as 1.3 times (1.2 times in Uttar Pradesh) average loss factors. In Maharashtra study, loss factors are determined by taking the average of those calculated for Andhra Pradesh and Uttar Pradesh. Since factors should be determined specifically for the system concerned, the Punjab study assumes peak load loss factors to be 10% higher than average loss factors whereas most studies assume those to be 30% higher.

Instead of reproducing marginal cost based tariffs in nine SEB's we have chosen the results for Uttar Pradesh SEB, as an illustration. Table 3 shows comparison of marginal cost tariffs and existing tariffs in UPSEB for different consumer/customer groups. Except in the case of street lighting, tariffs computed on the basis of marginal methodology are substantially higher than those charged during the planning horizon (1976-81).

The detailed algebraic formulation of marginal cost methodology is summarized in Appendix.

Table 3: Comparison of Marginal Cost Based Tariffs and Existing Tariffs in Uttar Pradesh

SL. No.	Category Consumer	Basis	Existing Tariffs Paise/Unit	Marginal Cost Based Tariffs Paise/Unit
1.	Light and Fan	5 hours basis	50.00	96.2 per KWH
2.	Small Power	8 hours Diversity 1.4	35.00	53.0 per KWH
3.	LT Industrial (0.4 KV)	Diversity 1.4, Power factor 0.8.	38.00	Rs. 67.0 per KVA MD/month + 18.1 paise per KWH
4.	LT Mixed Load (0.4 KV)	Diversity 1.2, Power factor 0.8.	45.00	Rs. 78.17 per KVA MD/month + 18.1 paise per KWH
5.	11 KV Industrial	Diversity 1.4, Power factor 0.8.	38.00	Rs. 58.81 per KVA MD/month + 16.05 paise per KWH (18.94 paise per KWH for L & F sub-meter in addition).
6.	33 KV Industrial	Diversity 1.4, Power factor 0.8.	36.10	Rs. 55.49 per KVA MD/month + 14.8 paise per KWH (17.16 paise per KWH for L & F sub-meter in addition).
7.	Above 33 KV Industrial	Diversity 1.4, Power factor 0.8.	35.15	Rs. 54.26 per KVA MD/month + 13.95 paise per KWH (18.0 paise per KWH for L and F sub-meter in addition).
8.	Street Light	10 hours working	50.00	57.18 paise per KWH

Source: Electricity cost determination on marginal cost principles, Uttar Pradesh State Electricity Board (1976-1981).

Conclusion

The rationale for designing electricity tariffs to reflect the marginal costs of supply electricity is Generally accepted. Such tariffs help to ensure that resources will be allocated efficiently in the Indian power sector. In some cases, tariffs may depart from long run marginal costs, as outlined in earlier

sections, in order to satisfy other economic (second best), financial, social (equity) objectives. The tariff structure can, thus, be forward looking only if the cost estimates and attendant assumptions (conditions) under which incremental amounts of electricity are supplied, are forward looking in nature.

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APPENDIX

A. METHOD OF ESTIMATING MARGINAL COST

(1) $E_g = MGC\ (1 + f)$

(2) $C_g = 1/12\ (AC_k + OM_g)\ (1+Q)\ (1+q) + AC_t + OM_t)$

where

E_g : marginal energy cost per KWH demanded at the supplying end of the transmission system,

MGC : marginal generating cost,

f : an allowance for auxiliaries and transmission losses,

C_g : marginal capacity cost per KW demanded at the supplying end of the transmission system per month,

A : annuitizing factor $\dfrac{r\ (1+r)^n}{(1+r^n) - 1}$

r : interest rate (%)

n : plant life (years)

C_k : marginal generation capacity cost per KW of capacity

C_t : marginal transmission cost per KW demanded at the supplying end of the transmission system,

Q : capacity margin in generating plant (percentage)

q : an allowance for transmission losses,

OM_g : annual operation and maintenance costs per KW of capacity for generation,

OM_t : annual O & M costs per KW of capacity for transmission.

B. DISTRIBUTION CAPACITY COST

$$MC_{33} = \frac{R_c}{R_m} C$$

$$MC_{33/11} = C_{33/11} (1+p)$$

where MC_{33} : marginal cost of 33 KV line per KVA demanded on the 11 KV side of a 33/11 KV transformer,

R_c : rate of increase in KM per year of 33 KV line,

R_m : rate of increase in KVA per year of maximum demand on the 11 KV side of 33/11 KV transformer,

C_{33} : cost per KM of 33 KV line,

$MC_{33/11}$: marginal capital cost of 33/11 KV substations per KVA demanded,

$C_{33/11}$: cost per KVA of capacity of 33/11 KV substations,

p : capacity margin

C. DISTRIBUTION CAPACITY COST TO HT AND LT CONSUMER

D_{HT} = $1/12\ A(MC_{33}+MC_{33/11})\ L^*_{33}\ L^*_{33/11}$
= monthly marginal cost of distribution capacity to an HT consumer at time of distribution peak,

E_{HT} = $L_{33}\ L_{33/11}\ E_g$
= marginal cost of energy to an HT consumer,

C_{HT} = $L^*_{33} \cdot L^*_{33/11}\ C_g$
= monthly marginal cost of generation and transmission capacity to an HT consumer at time of system peak,

C_{LT} = $L^*_{33}\ L^*_{33/11} L^*_{LT} C_g$,

E_{LT} = $L_{33} \cdot L_{33/11} \cdot\ L_{LT}\ E_g$,

$L^*_{33/11}$ D = 1/12 A (MC +MC +MC +MC +MC)

L^*_{LT}

L_{33}, L^*_{33} = annual average and peak period loss factors on 33/11 transformers and 11 KV lin

L_{LT}, L^*_{LT} = annual average and peak period loss factors on distribution transformers and LT line,

$L_{33/11}$, $L^*_{33/11}$ = annual average and peak period loss factors on 33/11 KV transformers and 11 KV line.

$MC_{VL} = \dfrac{R_{VL} C_{VL}}{R_{LT}}$ marginal cost of LT line per KVA of LT demand at time of distribution peak

$$MC_{11} = \frac{R_{11}(1-H)\ C_{11}\ L^*_{VL}}{R_{LT}} \quad \text{Div.} \quad \frac{R_{11}\ C_{11}}{R_{LT}}$$

$$R_{LT} = \frac{R_m\ (1-h)}{L^*_{33/11}\ L^*_{LT}}$$

= rate of increase per year of LT consumer demand supplied by 33/11 KV transformers at time of peak demand on these sub-stations (assuming that this coincides with distribution peak at lower voltage levels),

$$MC_{DT} = \frac{R_{DT}\ C_{DT}}{R_{LT}}$$

= marginal cost of distribution transformers per KVA of LT demand at time of distribution peak

where,

h = percentage of demand that is HT

R_{11} = rate of increase of 11 KV lines in Km per year

C_{11} = cost of 11 KV line per km

MC_{11} = marginal cost of 11 KV line per KVA of LT demand at time of distribution peak

R_{DT} = rate of increase in firm capacity of distribution transformer per year

C_{DT} = cost per KVA of firm capacity of distribution transformer

R_{VL} = rate of increase of Km of LT line per year

C_{VL} = cost per km of LT line

D. MARGINAL COST BASED TARIFFS (TIME-OF-DAY METERING)

HT CONSUMER :

$$\text{Price/KW} = C_{HT}\left(\frac{c}{a}\right) d_1 + D_{HT}\left(\frac{b}{a}\right) d_2$$

LT CONSUMER :

$$\text{Price/KW} = C_{LT}\left(\frac{c}{a}\right) d_1 + D_{LT}\left(\frac{b}{a}\right) d_2$$

where,

C_{HT}, C_{LT} = tariff to apply monthly to the average demand reading at the time of system peak,

D_{HT}, D_{LT} = tariff to apply monthly to the average demand reading at the time of distribution peak,

d_1, d_2 = diversity factors at system and distribution peak within consumer category,

a, b, c = peak KW demands for consumer category, peak KW demands for consumer category at distribution and system peaks respectively

Here, a maximum demand tariff has to approximate to the marginal capacity costs. We can make a reasonably accurate estimate of a consumers' contribution to system and distribution maximum demand per unit of his own maximum demand, if we have an estimated daily load curve for his consumer category.

E. MARGINAL COST BASED TARIFFS (NO DEMAND METERING)

We have to estimate the number of KW demanded at distribution and system peak per KWH consumed. If S represents the area under the consumer category typical daily load curve, b/s gives the number of KW demanded at peak per 24 houus of KWH consumption, and 24 b/s yields the number of KW demanded at time of distribution peak per KWH consumed.

Hence, a combined KWH and KW charge per measured KWH will be:

(i) $$\frac{24}{S}(ad_1 C_{LT} + bd_2 D_{LT}) + E_{LT}$$

(ii) $$\frac{24}{S}(ad_1 C_{HT} + bd_2 D_{HT}) + E_{HT}$$

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